

Corrosion inhibition of oil-well steel (N-80) in simulated hydrogen sulphide environment by ferrous gluconate and synthetic magnetite

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Selected environmentally benign iron compounds (synthetic magnetite and ferrous gluconate) have been evaluated as corrosion inhibitors for oil-well steel (N-80) in 50 mg/l sulphide concentration at various pH ranging from 5.5 to 11.5 and at High Temperature, High Pressure (HTHP) conditions by the weight loss method. The test temperatures were 150 °F, 275 °F and 350 °F respectively for pressures of 3 000 psi, 5 000 psi and 6 000 psi. The ferrous complex was found to be a better corrosion inhibitor compared to the synthetic magnetite. It exhibited up to 99.2% inhibition efficiency (IE) when the dose of the scavenger was doubled (i.e. when the sulphide to scavenger ratio was 1:2) irrespective of other factors such as pH, temperature and pressure. Whereas, the synthetic magnetite's optimum inhibition efficiency (IE) was observed to be up to 75.1% only when the ratio of the sulphide to scavenger was 1:4 at the lowest pH of the experiment (pH 5.5) which is not desirable for a drilling mud. As the pH increases, the inhibition efficiency of the magnetite decreases and found to be lowest at the alkaline pH of 11.5.

Key words: corrosion inhibition, drilling fluid, environmental-benign, ferrous gluconate, oil-well steel, sulphides, synthetic magnetite

1. Introduction

Hydrogen sulphide gas, H₂S, is a naturally occurring, often found below the surface of the earth, in zones below which oxidation of minerals does not occur.¹³ Corrosion of drill pipe, protective casing strings and other related equipment is recognized as a serious problem that requires control. Historically, the industry has been interested in functional methods of controlling corrosion while drilling. Quite often the methods, even though effective, were designed to provide protection to certain portions of the exposed equipment perhaps leaving the rest unprotected. An example of this is internally plastic coated drill pipe. These coatings are functional where they are properly applied and remain bonded. The protective plastic coatings cover one of the trouble spots, but the external surface of the drill pipe and the internal surface of the casing remain exposed and subject to corrosive failure. Other examples of specific corrosion protection are sealed bearing bits and alloy selection for casing or pressure control equipment. Specific protection of various components is needed, but overall protection is also important. The treatment of drilling fluid to combat corrosion provides the best common medium for overall control.

The problems associated with sour production are well known: toxic, corrosion, excess solids, emulsion and surface equipment problems, and of course, the necessity to remove H₂S prior to sale. Multi millions of dollars are spent every year on detection and mitigation of weight loss and other kinds of corrosion in oil and gas industry equipment. Although an abundance of literature describ-

ing the abatement of hydrogen sulfide in gas and drilling fluid systems is available, majority of these techniques and environments do not appear to have significant utility in oilfield operations when HSE (health, safety and environmental) is put into consideration. Though the methods like aeration, bacteria, chemical scavengers metallic salt and oxide beds and oxidizers used in other industries-such as the geothermal, pulp and paper, and wastewater industries have some application in oilfield production, the most of them appear impractical because of cost and compatibility consideration.

The purpose of this paper is to present a potential solution to the problem that involves the laboratory testing on H₂S scavenger and corrosion control effects of a new H₂S scavenger for drilling operations by simulating the realistic rig-site operating conditions. In order to better understand the problem, the kinds of corrosion and mechanism caused by hydrogen sulphide and its commercial scavenger will be briefly reviewed.

2. Theory

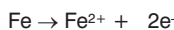
2.1. Corrosion caused by Hydrogen Sulphide

Since corrosion processes involve electrochemical reactions, it is important to take a look at how hydrogen sulphide takes part in the reaction bringing about the corrosion.

The corrosion of iron in the presence of hydrogen sulphide and water is dependent upon the dissociation of the hydrogen-sulphide molecule. Iron is oxidized to the ferrous form at the anode and hydrogen sulphide under-

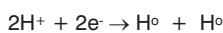
goes a two-step -dissociation at the cathode. Tung *et al* propose the following equilibrium reactions below.

At the anode:

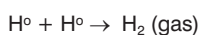


and at the cathode hydrogen is produced and either enters the steel or forms hydrogen gas and bubbles off:

if H_2S is present:



if H_2S is not present:



Hydrogen enters the steel first by adsorption onto the water to steel interface and then by being absorbed into the steel as hydrogen. The amount of hydrogen entry depends on the corrosion rate of the steel surface and the concentration of anions such as HS^- that reduce the tendency to produce hydrogen gas (as shown in second equation above) and promotes the hydrogen (H^0) to enter the steel.

Acid concentration influence, typically related to pH, has an influence on amount of corrosion damage.

at $\text{pH} > 4$



at $\text{pH} < 4$



which then leads to either hydrogen charging of the steel with hydrogen or hydrogen gas evolution.¹³

2.2. Hydrogen Sulphide Scavengers

There are several hydrogen sulphide scavengers that are used in the oil industry. The type of the scavenger needed

for a specific field application depends, among other factors, on the pH and the form of hydrogen sulphide present in solution. Depending on the pH, hydrogen sulphide can be present in one of three forms: molecular H_2S , which is present at low pH values, ionic hydrogen sulphide (HS^-), and sulphide (S^{2-}) which is present at high pH values. Each of the three species is stable over a certain pH range and they are related to each other as described in the following equation:



Among the common scavengers, the most HSE compliant scavenger used in drilling fluids so far is the magnetite but the limitation attached to it is its low reaction rates in high pH muds and faster reaction rates in low pH muds. This is not desirable for muds therefore muds' pH are not usually allowed to go below 9.5. The pH is normally maintained between 10 and 11.5 so as to serve as the first prophylactic measure in case H_2S is contacted downhole.⁷ Commercial zinc-containing compounds (ZCCs) have proved to be effective but they upset rheology and pose environmental problems during cuttings disposal.¹² The reports on the chlorine-containing compounds (CCCs) e.g. sodium hypochlorite and organic compounds e.g. ethylenediamine tetraacetic acid – EDTA indicates that their reactions with hydrogen sulphide are too complex to be predicted besides the outstanding questions concerning health, safety and environmental aspect of these reactants and their reaction products.¹¹

3. Experimental

3.1. Materials and Instruments

Commercially available ferrous gluconate and magnetite were used as scavengers. The water based mud used is saturated brine mud (mud's composition shown in Table 1). Analar grade reagents of Potassium hydroxide, HCl, sodium sulphide pellets were used.

Instruments such as pH meter (model OMEGA PHH-3X), Precision Weighing Balance (model GD-503), Corrosion Autoclave (model CORTEST 12.45) were used. Oil-well steel coupon (N-80 Steel) specimens of specification 50 x 12 x 2 mm of which the composition is shown in Table 2 were used for the corrosion tests using the weight loss method.

3.2. Procedure

In a certain range of hydrogen sulphide concentration, sulphide stress cracking and electrochemical corrosion of drilling tools increase as the amount of sulphide in mud increases.^{13,4} Oil-well steel coupon (N-80 Steel) specimens of specification 50 x 12 x 2 mm of which the composition is shown in Table 2 were used for the corrosion tests using the weight loss method. The weight of each coupon was determined before it was subjected to the weight loss test. This test was carried out in a small,

Table 1. Composition of the Saturated Brine Mud

Constituents	Concentration
Sodium chloride	80 lb/bbl
Caustic potash (KOH)	1.5 lb/bbl to pH of 12
Soda ash (sodium carbonate)	0.11 lb/bbl
API Bentonite	20.0 lb/bbl
polyanionic cellulose	1.7 lb/bbl
Pregelatinized corn starch	2.0 lb/bbl
Chrome lignosulphonate	4.0 lb/bbl
Alcohol-based defoamer	2.0 lb/bbl
sodium bisulphate	1.2 lb/bbl
API barite – barium sulphate of SG 4.2	15.0 lb/bbl
Xanthan gum	0.85 lb/bbl

Table 2. Chemical Composition of the N80 Steel Coupon

Element	Fe	C	Mn	P	S	Si	Cr	Ni	Mo
Wt. %	97.237	0.44	1.74	0.019	0.014	0.24	0.12	0.02	0.20

high temperature Corrosion Autoclave (CORTEST Model 12.45) containing the mud with 50 mg/l of sodium sulphide.

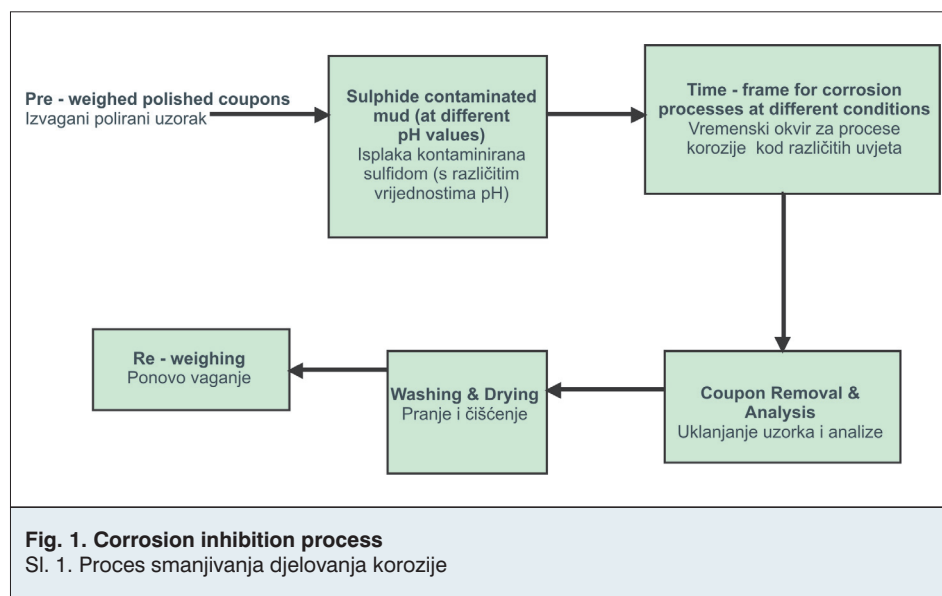
The pH values used for the tests were 5.5, 7.5, 9.5 and 11.5. Then an oil-well steel coupon (N-80 Steel of size 50 x 12 x 2 mm) which had been treated according to the API specifications (API RP-13 B-1) was hung in the mud.⁸ The high-temperature weight-loss tests were conducted using a standard corrosion autoclave. This device is capable of holding 12 eight-ounce bottles in a carbon steel rack, and is rated at 10 000 psi (68.9 MPa) to 393 °F (200 °C). The corrosion coupons were hung from glass hooks in eight-ounce bottles that contained saturated brine mud, sodium sulphide and then the scavenger under test, each of known proportions. The bottles were placed in the rack, and then lowered into the autoclave. The autoclave was closed and heated to the test temperature at 10 °F/min until the temperature reaches the desired temperature of 150 °F (66 °C), 275 °F (135 °C) or 350 °F (177 °C) separately in each case. Once the temperature stabilized, the vessel was pressurized to 3 000 psi (20.7 MPa) for 150 °F (66 °C), 5,000 psi (34.5 MPa) for 275 °F (135 °C) and 6 000 psi (41.4 MPa) for 350 °F (177 °C) respectively, and the test rack was agitated at 60 rpm. The test duration was four hours at each temperature and pressure set, after which the autoclave was cooled at about 6 °F/min to room temperature and the samples removed.

A set of the tests was done without the application of any scavenger to serve as a control.

In the control tests, an N-80 coupon was inserted to measure the corrosion of the test mud having 50 mg/l concentration of the sulphide, and at different conditions of temperatures and pressures but with none of the scavengers added. The control test was in three categories. Each group was run at different pHs of 5.5, 7.5, 9.5, and 11.5 respectively. The first category was run at 150 °F (66 °C) and 3 000 psi (20.7 MPa), the second at 275 °F (135 °C) and 5 000 psi (34.5 MPa), and the third at 350 °F (177 °C) and 6 000 psi (41.4 MPa).

This was done in order to know the level of the corrosivity of the sulphide contaminated mud without the application of a scavenger at such varying values of pHs. Then, same amount of the scavengers (50 mg/l) was applied to inhibit the corrosion rates obtained in the control tests.

The inhibition test was not limited to the 1:1 of the scavenger concentration to sulphide concentration (i.e. 50 mg/l of scavenger against 50 mg/l of sulphide). Scavenger concentration to sulphide concentration ratio of 2:1, 3:1 and 4:1 were also applied during corrosion inhibition tests.



After the test duration of four hours, the coupons were removed from the autoclave and analyzed in the following ways according to API specifications.

The coupons were scrubbed with bristle brush to remove the corrosion products; the corrosion products were carefully observed and then tested in acid arsenic solution.

The test for the presence of hydrogen sulphide was carried out, the coupons were then cleaned in acetone, dried and reweighed to get the corrosion rate.

The corrosion rates in (mm/y) were calculated for each weight loss using the relation shown below in the equation below:³

$$CPR = \frac{87.6 W}{\rho A t}$$

where:

- CPR = corrosion Penetration rate (mm/y)
- W = weight loss after the test (g)
- ρ = density of the specimen (g/cm³)
- t = time of exposure (hr)
- A = area of exposure (cm²)

Figure 1 represents the corrosion inhibition process.

4. Results and Discussion

4.1. Control Tests

Figure 2 and 3 shows results of the control.

The Figures 1,2 and 3 indicate that, the corrosion rate for the oil-well steel was dependent on the sulphide concentration and the pH of the medium. Temperature as well has an effect on the corrosion rate. The highest corrosion rate was 0.518 mm/y at 150 °F (66 °C), 1.452 mm/y at 275 °F (135 °C) and 1.887 mm/y at 350 °F (177 °C), all at the lowest pH of 5.5. Also at the highest (alkaline) pH of 11.5, the highest corrosion rate was 0.101 mm/y at 150 °F (66 °C), 0.282 mm/y at 275 °F (135 °C) and 0.367 mm/y at 350 °F (177 °C). All these can be ob-

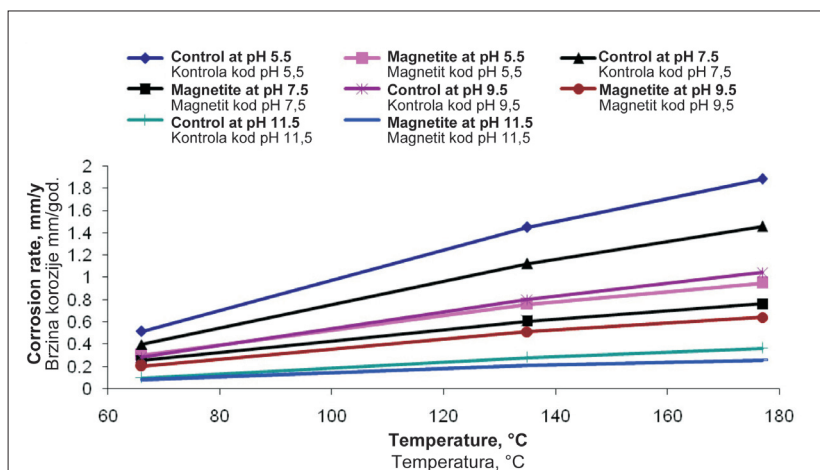


Fig. 2. Dependency of corrosion rate on temperature and pH in 50 mg/l sulphide and 50 mg/l of magnetite

Sl. 2. Ovisnost brzine procesa korozije o temperaturi i pH kod koncentracije sulfida od 50 mg/l i magnetita od 50 mg/l

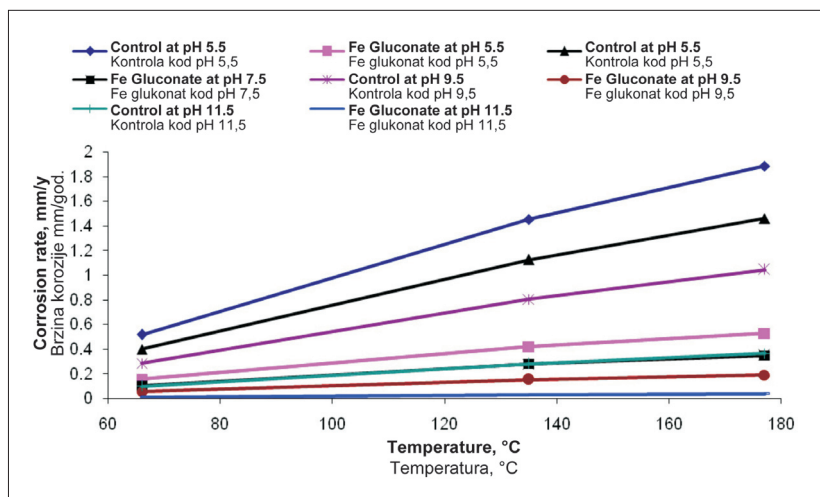


Fig. 3. Dependency of corrosion rate on temperature and pH in 50 mg/l sulphide and 50 mg/l of ferrous gluconate.

Sl. 3. Ovisnost brzine procesa korozije o temperaturi i pH, kod koncentracije sulfida od 50 mg/l i željeznog glukonata od 50 mg/l

served from the control tests. In these tests, there is an indication that increase in temperature was also a factor that led to the increase in corrosion rates.

Visual observation of the corroded coupons in the absence of the inhibitors clearly revealed black spots on their surfaces. Black corrosion products were formed on the coupons, which is an indication of the presence of hydrogen sulphide. When the black product was tested in arsenic acid solution, a bright yellow precipitate was obtained thus confirming the corrosion product to be iron sulphide. Also from the microscopic inspections (plates 1 and 2), pitting forms of corrosion was observed. The pitting occurred in the form of deep and large pits (plates 1 and 2). The pitting corrosion can be said to be respon-

sible for the high corrosion rates of the coupons in the absence of the inhibitors.

The corrodibility of the steel by hydrogen sulphide strongly depends on the pH of the medium. The normal trend is that when the pH is low, the corrosion rate increases fast as observed in the control test. Garrett *et al*⁵ reported that in low pH medium, hydrogen sulphide mainly exists in molecular form (H_2S). Therefore, the hydrogen sulphide concentration in the gas phase also increases and accelerates the corrosion rates. However, at high pHs, the weight lost to corrosion was low compared with those obtained at low pHs. The lower the pH, the higher the acidity of the medium which aggravates the corrosion rates and the higher the pH, the higher alkalinity of the medium which mitigates against the corrosion.

The effectiveness of the ferrous gluconate in reducing the corrosion rates obtained in control tests can be observed from Figure 3. In the Figures, the same stoichiometric amount of sulphide and scavenger was put to test (i.e. sulphide:scavenger was 1:1). This means that in Figure 3 where 50 mg/l of the sulphide concentration was used as the medium for the corrosivity, 50 mg/l of the ferrous gluconate was applied to scavenge the sulphide and inhibit the corrosion rate. In the Figure, at 150 °F (66 °C), and pH of 5.5, the corrosion rate was reduced from 0.518 mm/y to 0.156 mm/y with the aid of ferrous gluconate whereas, magnetite in Figure 2 was only able to reduce the same corrosion rate to 0.304 mm/y. At alkaline pH of 11.5 for the same temperature 150 °F (66 °C), as above, ferrous gluconate (in Figure 3) was able to reduce the corrosion rate from 0.101 mm/y to 0.011 mm/y but magnetite (in Figure 2) was only able to reduce the same corrosion rate to 0.080 mm/y. From Figures 2 and 3, it can be observed that the ferrous gluconate was able to mitigate against the corrosion of the oil-well steel significantly throughout the various conditions of pH and temperature because the corrosion rates were significantly lowered.

4.2. Corrosion Inhibition Tests

The following are the results obtained for the corrosion inhibition efficiency of the two scavengers. Figures 4 – 6 show the results for the corrosion inhibition tests.

Figures 4 – 6 compare the action of the two scavengers at various conditions of temperature and pressure. The test conditions were 150 °F (66 °C) and 3 000 psi (20.7 MPa); 275 °F (135 °C) and 5 000 psi (34.5 MPa) and; 350 °F (177 °C) and 6 000 psi (41.4 MPa); and at various pHs and scavenger concentrations. The tests were performed

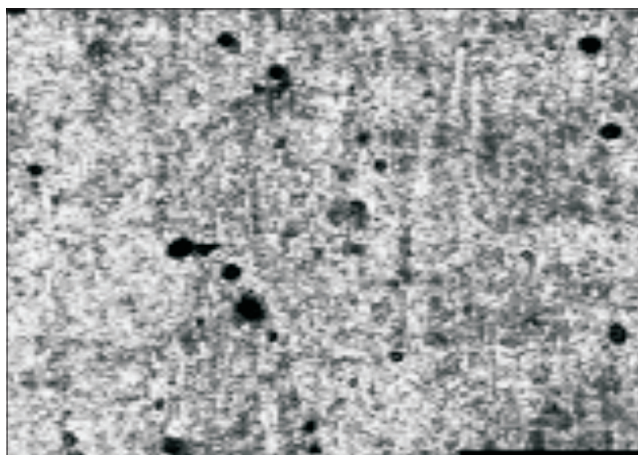


Plate 1. Pitting at 150 °F, pH 5.5, 50 mg/l sulphide, no scavenger added. Focus: $\times 100$

Pločica 1 Točkasto korodiranje na 150 °F (66 °C), pH 5,5 i 50mg/l sulfida, bez dodanog pročištača. Fokus x 100

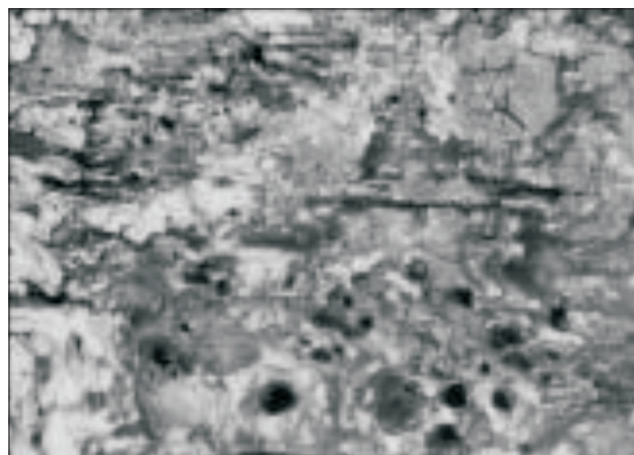


Plate 2. Pitting at 350 °F, pH 5.5, 50 mg/l sulphide, no scavenger added. Focus: $\times 100$

Pločica 2 Točkasto korodiranje na 350 °F (177 °C), pH 5,5 i 50mg/l sulfida, bez dodanog pročištača. Fokus x 100

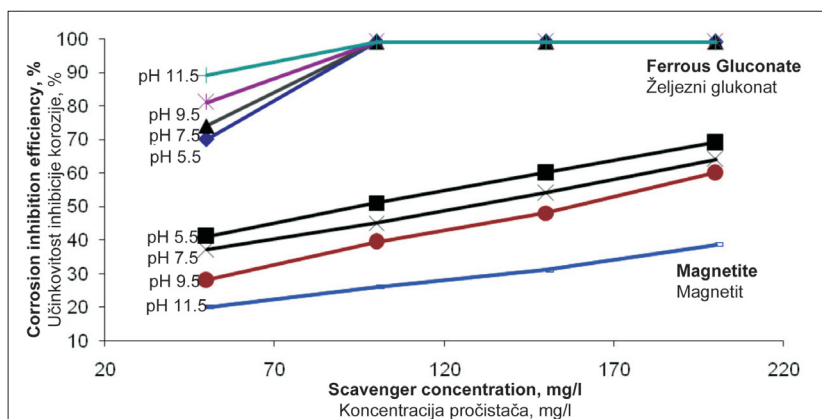


Fig. 4. Corrosion inhibition efficiency of the two scavengers in 50 mg/l sulphide at various scavenger concentrations, 150 °F (66 °C) and 3 000 psi (20.7 MPa)

Sl. 4. Učinkovitost usporavanja procesa korozije za dva pročištača u 50 mg/l sulfida, kod različitih koncentracija pročištača, na 66 °C (150 °F) and 20,7 MPa (3 000 psi)

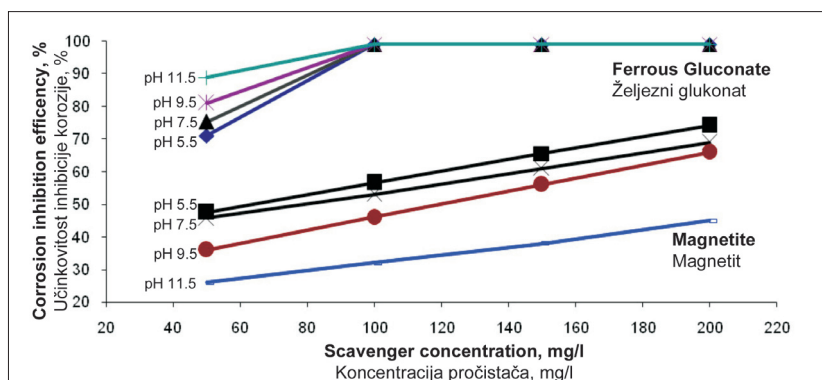


Fig. 5. Corrosion inhibition efficiency of the two scavengers in 50 mg/l sulphide at various scavenger concentrations, 275 °F (135 °C) and 5 000 psi (34.5 MPa)

Sl. 5. Učinkovitost usporavanja korozije za dva pročištača u 50 mg/l sulfida kod različitih koncentracija pročištača, na 135 °C (275 °F) i 34,5 MPa (5 000 psi)

on both scavengers in order to compare their corrosion inhibition strengths.

A careful look at the Figures shows that the corrosion inhibition effects are dependent on the scavenger concentration and the pH (or the corrosivity) of the medium.

For the medium containing 50 mg/l of sulphide concentration, the inhibition efficiency of the ferrous gluconate reached at least 70% with the first dose of the inhibitor concentration at the acidic pH of 5.5 and the efficiency reached at least 89% at the alkaline pH of 11.5 throughout the tests. Interestingly, the inhibition reached almost 100% when the inhibitor dosage was doubled, i.e. when the inhibitor concentration to sulphide ratio was in a ratio of 2:1 in all the pH conditions as could be observed from the Figures. This indicates increase in efficiency as the pH and scavenger concentration increases. Also, inhibition efficiency of the ferrous gluconate improved a little bit as the temperature and pressure conditions (275 °F/135 °C and 350 °F/177 °C) and (5 000 psi/34.5 MPa and 6 000 psi/41,4 MPa) respectively were raised.

Cross examination of the micrographs of the coupons after been subjected to corrosion test in the presence of the ferrous gluconate revealed that black iron sulphide scales on the coupons disappeared, pitting corrosion was markedly reduced and the weight loss of the coupons decreased distinctly (plates 5, 6, 7 and 8).

In the case of the magnetite application, the scavenger performed better in lower pH conditions than in higher pHs, i.e. the lower the pH of the medium, the higher the

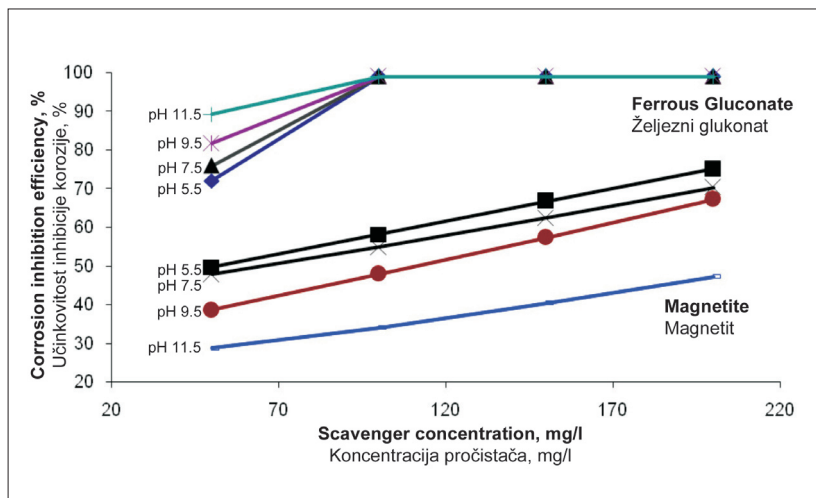


Fig. 6. Corrosion inhibition efficiency of the two scavengers in 50 mg/l sulphide at various scavenger concentrations, 350 °F (177 °C) and 6 000 psi. (41.4 MPa)

Sl. 6. Učinkovitost usporavanja korozije dva pročištača u 50 mg/l sulfida kod različitih koncentracija pročištača, na 177 °C (350 °F) and 41,4 MPa (6 000 psi)

inhibition efficiency of the scavenger (see plates 3 and 4). The best performances of the scavenger in the Figures occurred at the lowest pH of 5.5 throughout the tests. For instance, it achieved 69% efficiency at pH of 5.5 and only of 38.5% efficiency at alkaline pH of 11.5 only when the ratio of the scavenger concentration to sulphide concentration of 4:1 was applied. It could be observed from the Figures that elevated conditions of temperature and pressure assisted in the increase in the reaction rates of the scavengers with the sulphide.

At temperature of 275 °F (135 °C) and pressure of 5 000 psi (34.5 MPa), magnetite achieved 74.1% efficiency at pH 5.5 and only 45% efficiency at the alkaline pH of 11.5 also when the ratio of the scavenger concentration to sulphide concentration of 4:1 was applied. Then at 350 °F (177 °C) of temperature and 6 000 psi (41.4 MPa) of pres-

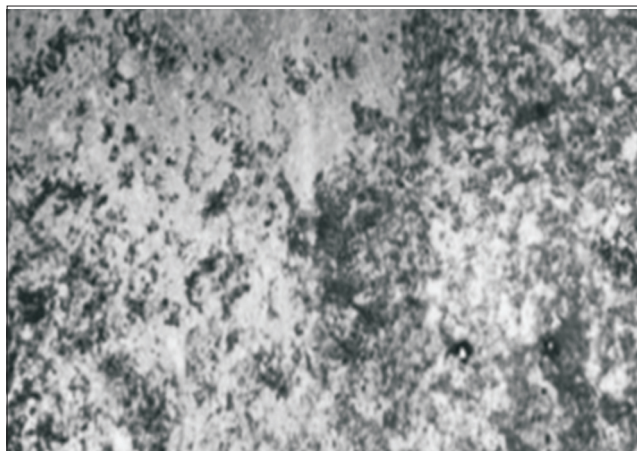


Plate 3. Pitting at 177 °C (350 °F), pH 11.5, 50 mg/l sulphide, 200 mg/l magnetite. Focus: ×100
Pločica 3 Točkasto korodiranje kod 177 °C (350 °F), pH 11,5; 50mg/l sulfida, 200 mg/l magnetita. Fokus x 100

sure, it exhibited 75.1% efficiency at the acidic pH of 5.5 and just 47.2% efficiency at the alkaline pH of 11.5 only when the ratio of the scavenger concentration to sulphide concentration of 4:1 was applied. This has been confirmed from the literature that reaction of magnetite with sulphide actually proceeds faster at low pH values.¹² But it is not a desirable characteristic for a sulphide scavenger. Further increase in the pH lowered the corrosion efficiency of the magnetite contrary to what was observed in the case of ferrous gluconate. The aforementioned high efficiencies were observed only when the magnetite concentration to sulphide ratio was 4:1 contrary to that of ferrous gluconate which its corrosion inhibition efficiency reached almost 100% just when the ratio of the scavenger concentration to sulphide concentration of 2:1 was applied. There is an indication that the efficiency will keep on increasing as much as there is an increase in magnetite's amount. This is usually not desirable because according to Alvin¹ and Ray *et al.*,¹² magnetite can be substituted for barite in drilling muds and this indicates that magnetite adds to the weight of a mud. Addition of higher amounts of it can upset rheology as lifting and suspension of the mud during hole cleaning will become a problem. Upon the analyses of the micrographs of the corroded coupons in which the magnetite was added, the corrosion products were still building up on the coupon, with pits below the deposits clearly showing the failure to control corrosion effectively. The weight loss and the corrosion rates were still significant. It can be observed from plates 3 and 4 that there were still considerable pitting effects when magnetite was applied even at 4:1 of magnetite concentration to sulphide concentration ratios.

Since the inhibition efficiency of the magnetite was lower at alkaline pHs compared to the results at acidic

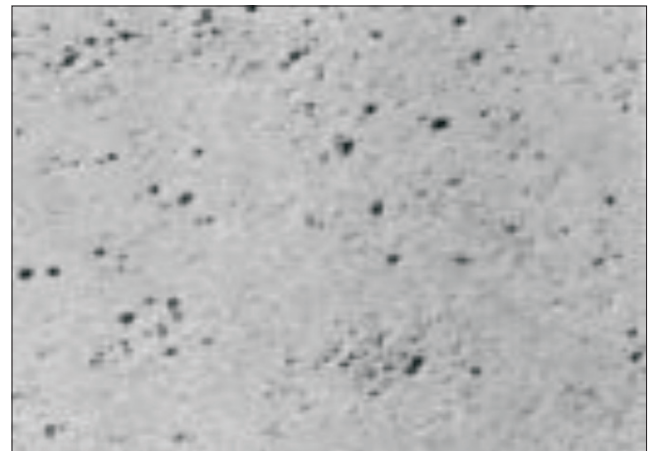


Plate 4. Pitting at 177 °C (350 °F), pH 5.5, 50 mg/l sulphide, 200 mg/l magnetite. Focus: ×100
Pločica 4 Točkasto korodiranje kod 177 °C (350 °F), pH 5,5; 50mg/l sulfida, 200 mg/l magnetita. Fokus x 100



Plate 5. Reduced pitting at 350 °F (177 °C), pH 11.5, 50 mg/l sulphide, 50 mg/l ferrous gluconate.
Focus: ×100

Pločica 5 Smanjeno točkasto korodiranje kod 350 °F (177 °C), pH 11,5; 50mg/l sulfida, 50 mg/l željeznog glukonata.
Fokus x 100

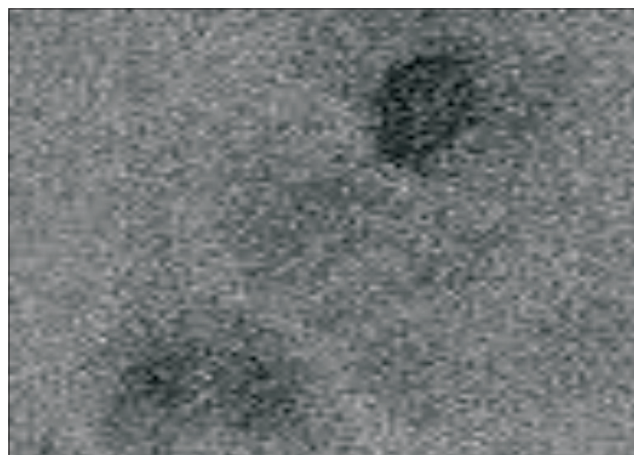


Plate 6. Reduced pitting at 350 °F (177 °C), pH 5.5, 50 mg/l sulphide, 50 mg/l ferrous gluconate.
Focus: ×100

Pločica 6 Smanjeno točkasto korodiranje kod 350 °F (177 °C), pH 5,5; 50mg/l sulfida, 50 mg/l željeznog glukonata.
Fokus x 100

pHs. This is an indication that magnetite is not a suitable scavenger when using high pH muds because the standard in the drilling fluid technology is that muds should not be allowed to go below pH of 9.5 so as to be able to mitigate most corrosion⁸; muds are normally kept in the pH range¹⁰ between 10 and 11.5. And no matter what the case may be, drastic pH decrease to less than 5 is unlikely to occur in a drilling fluid.⁵

5. Conclusions and recommendations

5.1. Conclusions

From the results obtained in this research, it was concluded that:

1. The investigated corrosion rate of N-80 steel in the H₂S contaminated mud is very rapid; it can reach 2.5 mm/y (100 mpy).
2. The corrosion rate is dependent on the hydrogen sulphide concentration, pH of the medium and the temperature condition of the environment.
3. Ferrous gluconate can reduce the corrosion of drill string and mud lines. Its corrosion inhibition efficiency reached almost 100% when the dose was doubled, thus preventing drill strings from pitting corrosion, hydrogen embrittlement and sulphide stress cracking. Magnetite had its highest inhibition efficiency (about 70%) at the lowest pH when the magnetite to sulphide ratio 4:1.

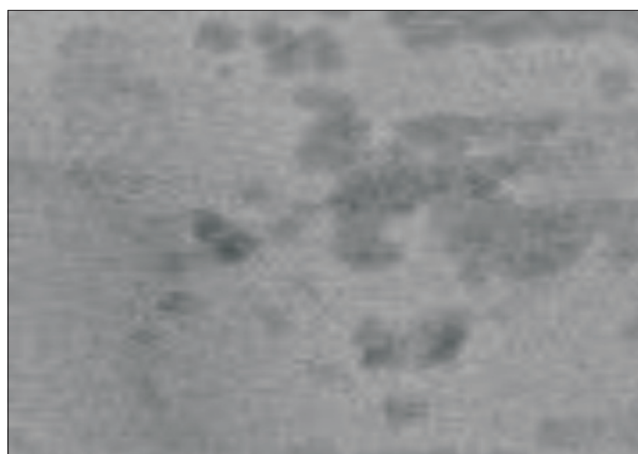


Plate 7. Clean coupon surface at 350 °F (177 °C), pH 5.5, 50 mg/l sulphide, 100 mg/l ferrous gluconate.
Focus: ×100

Pločica 7 Smanjeno točkasto korodiranje kod 350 °F (177 °C), pH 11,5; 50mg/l sulfida, 50 mg/l željeznog glukonata.
Fokus x 100



Plate 8. Clean coupon surface at (350 °F) (177 °C), pH 5.5, 50 mg/l sulphide, 100 mg/l ferrous gluconate..
Focus: ×100

Pločica 8 Smanjeno točkasto korodiranje kod 350 °F (177 °C), pH 5,5; 50mg/l sulfida, 50 mg/l željeznog glukonata.
Fokus x 100

4. Ferrous gluconate has the advantages of being more readily available and cheaper than synthetic magnetite.

Recommendations

Based on the research conducted, analyses and conclusions of this work, the following are recommended:

1. This information needs to be translated into realistic rig-site corrosion inhibition tests.
2. More research should be conducted on the existing organic products to identify their true corrosion inhibition capabilities under realistic wellbore drilling conditions.
3. Optimization of the corrosion inhibition processes of the ferrous gluconate should be looked into.

Acknowledgement

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